EVALUATION AND EFFECT OF FRACTURING FLUIDS ON FRACTURE CONDUCTIVITY IN TIGHT GAS RESERVOIRS USING DYNAMIC FRACTURE CONDUCTIVITY TEST

A Thesis

by

JUAN CARLOS CORREA CASTRO

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2011

Major Subject: Petroleum Engineering

Evaluation and Effect of Fracturing Fluids on Fracture Conductivity in Tight Gas

Reservoirs Using Dynamic Fracture Conductivity Test

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Approved by:

Co-Chairs of Committee,	Ding Zhu
	A. Daniel Hill
Committee Member,	Yuefeng Sun
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ABSTRACT

Evaluation and Effect of Fracturing Fluids on Fracture Conductivity in Tight Gas Reservoirs Using Dynamic Fracture Conductivity Test. (May 2011)

Juan Carlos Correa Castro, B.S., Universidad Industrial de Santander

Co-Chairs of Advisory Committee: Dr. Ding Zhu
Dr. Alfred Daniel Hill

Unconventional gas has become an important resource to help meet our future energy demands. Although plentiful, it is difficult to produce this resource, when locked in a massive sedimentary formation. Among all unconventional gas resources, tight gas sands represent a big fraction and are often characterized by very low porosity and permeability associated with their producing formations, resulting in extremely low production rate. The low flow properties and the recovery factors of these sands make necessary continuous efforts to reduce costs and improve efficiency in all aspects of drilling, completion and production techniques. Many of the recent improvements have been in well completions and hydraulic fracturing. Thus, the main goal of a hydraulic fracture is to create a long, highly conductive fracture to facilitate the gas flow from the reservoir to the wellbore to obtain commercial production rates. Fracture conductivity depends on several factors, such as like the damage created by the gel during the treatment and the gel clean-up after the treatment.

This research is focused on predicting more accurately the fracture conductivity, the gel damage created in fractures, and the fracture cleanup after a hydraulic fracture treatment under certain pressure and temperature conditions. Parameters that alter fracture conductivity, such as polymer concentration, breaker concentration and gas flow rate, are also examined in this study. A series of experiments, using a procedure of “dynamical fracture conductivity test”, were carried out. This procedure simulates the proppant/frac fluid slurries flow into the fractures in a low-permeability rock, as it occurs in the field, using different combinations of polymer and breaker concentrations under reservoirs conditions.

The result of this study provides the basis to optimize the fracturing fluids and the polymer loading at different reservoir conditions, which may result in a clean and conductive fracture. Success in improving this process will help to decrease capital expenditures and increase the production in unconventional tight gas reservoirs.

DEDICATION

This thesis is dedicated to my family

ACKNOWLEDGEMENTS

I would like to thank my co-chairs, Dr. Ding Zhu and Dr. A. Daniel Hill, for giving me the opportunity to study under them and pursue my Master of Science degree, and for their guidance and support throughout the course of this research.

Thanks also goes to Dr. Yuefeng Sun for serving as my committee member. I would also like to thank John Maldonado, Andres Pieve de La Rosa, Obadare Awoleke and Jose Romero, for their help and support and for making my time at Texas A&M University a great experience. Also, I would like to thank the Harold Vance Department of Petroleum Engineering for giving me the opportunity to pursue my masters degree and the Research Partnership to Secure Energy for America (RPSEA) corporation for funding this research project.

Finally, thanks to my mother and father for their encouragement.

TABLE OF CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

CHAPTER I

INTRODUCTION AND LITERATURE REVIEW

1.1 Hydraulic Fracturing in Tight Gas Reservoirs

Gas production from tight sand reservoirs has become an important source of natural gas supply in the United States due to its long-term production and its environmental cleanliness. In 2008, unconventional gas accounted for more than half of total gas production (around 58%) in the United States with tight gas sands representing the major fraction (around 38 %) of total unconventional gas production, suggesting it is an important source for future reserves growth and production. Tight gas reservoirs are expected to play a significant role in near future domestic gas market and to have significant impact in gas prices, see figure 1 (US Department of Energy, 2008).

Although abundant, these low-permeability gas reservoirs are locked in massive sedimentary formations which are difficult to produce. Despite their tremendous reserve growth potential, the exploitation of these reservoirs presents major technical and engineering challenges and their production requires special completion and stimulation technology in order to achieve a profitable production rates. Hydraulic fracturing is a common technique widely used to improve production from tight gas reservoirs. The main goal of a hydraulic fracturing treatment is to create a long, highly conductive hydraulic pathway to stimulate the flow of gas from the reservoir to the wellbore.

This thesis follows the style of *SPE Journal.*

Sufficient quantities of proppant material into the fracture are required to reach an effective cleanup of the fracture at the end of the treatment.

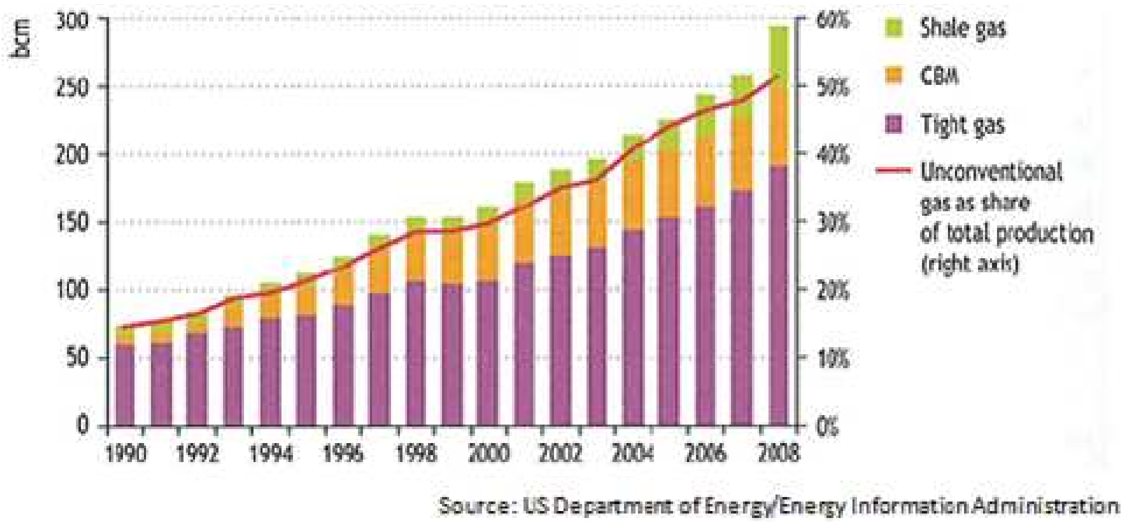

Figure 1—Unconventional gas production in the United States.

Over the last thirty years many experimental studies (Almond and Bland 1984, Hawkins 1988, Kaufman 2007 et al) have showed the importance of fracture conductivity and how the proppant pack is affected by fracturing fluid and closure stress. These experiments indicate that the fracturing fluid could cause damage to proppant packs, and also show how closure stress could affects the final conductivity. As a result, the industry began to use fracturing fluids with lower polymer loading (less than 30 lb/1000gal) and lower proppant concentration and, in some cases without proppant and/or polymer, with the intention of maintaining a clean fracture and avoiding damage caused by polymer. This treatment is also known as “water frac” and over the last thirty years “water fracs” have become popular. The first “water frac” was developed during late 1960s in San Juan basin area. Their popularity lies in the reduction in fluid costs and total fracture-stimulation costs that in some cases has revitalized development in low-permeability reservoirs.

1.2 Background and Literature Review

Producing tight gas reservoirs economically and efficiently requires unique and advanced drilling and completion techniques, i.e. horizontal drilling and well stimulation. Driven by current hydrocarbon prices, especially in the gas market, operators have focused their efforts to improve the productivity of these reservoirs and hence the development of new technologies and expertise.

Hydraulic fracturing is used to create narrow but extensive fractures deep into the formation in low permeability rocks, like tight gas reservoirs. Hydraulic fractures provide a passage for gas to move easier from the reservoir into the wellbore in order to attain an economical production rate. Investigations on fracturing fluids have permitted variations of fluids used in fracture treatments under different reservoir conditions and with the goal to obtain optimal fracture conductivity. Different researches had developed experiments to evaluate proppant packs and fracturing fluids performance under several pressure and temperature conditions.

The first attempt to measure short-term conductivity of proppant packs was developed by C. E. Cooke, Jr. using a conductivity cell (Cooke Jr., 1975). The fluid used in his experiment was a brine with polymer concentration between 50 to 90 lb/1000 gal as fracture fluid and gas or brine as produced fluid at high temperature (200 °F). The proppant pack was placed manually into the cell between two Berea cores and closure stress was applied using a steel piston. Closure stress was varied between 3000 and 8000 psi. The objective was to study the reduction of proppant pack conductivity caused by fracturing fluid residues at specific temperature.

Van der Vlis et al. (1975) carried out an investigation on a similar conductivity cell. The objective was to develop empirical correlations for the determination of fracture conductivity and design criteria for pumping schedules. The experiments were run with increasing closure stress step by step as follows: 500 psi, 1000 psi, 2000 psi, 4000 psi, 6000 psi and 8000 psi. Low and high viscosity fluids (10 to 100 cP) were used in the test and proppant concentration was varied from 5 to 10 lb/gal. Van der Vlis recommended as admittance criterion for fracture a width/maximum ratio of proppant diameter of 2 for 5 lb/gal and 1.8 for proppant concentration below 2 lb/gal. Additionally, they concluded that high viscosity non Newtonian fluid can transport proppant concentration of 8 lb/gal inside the fracture.

Volk, et al. (1983) studied the damage due of fracturing fluids. The polymer load was varied between 40 and 80 lb/1000gal. The experiment simulated reservoir conditions; the permeability was measured before and after the fluid was pumped across the surface of a low permeability core. The system was designed to evaluate core damage due to gelled fluid penetration and skin effect at simulated fracturing conditions. Core damage was estimated by measuring gas permeability. The hydrostatic stress applied on a core sample was 1000 psi, 1700 psi and 3000 psi. As a conclusion, the investigation shows that the invasion depth of unbroken gel is very small and the permanent damage remains constant at a given temperature (17-20 percent at 343°K) (Volk et al., 1983).

Almond and Bland (1984) investigated the effect of the break mechanism on gel residue and flow loss through sand pack caused by gel damage. The experiment was conducted on a sand pack cell using steel pistons instead of rock samples and no stress was applied to the proppant. Continuing this investigation, Kim and Losacano in 1985 studied the fracture conductivity damage due to injection of crosslinked gel and closure stress. They used a linear-flow proppant conductivity test cell and fluids with concentrations of 40 lbm/1000 gal and 70 lbm/1000 gal of polymer, breaker at a concentration of 25 percent of the polymer weight and borate cross-linker. The experiments were run at two temperatures, 120°F and 180 °F. The research concluded that the guar cross linked with borate has the largest volume of gel residue under the same break conditions, also, the increase polymer concentration from 40 lb/1000 gal to 70 lb/1000 gal generates proportionally higher gel residues, however, the damage to the sand permeability is not proportional. Finally, when increase closure stress decrease sand permeability (Kim and Losacano, 1985).

Roodhart (1985) investigated the proppant pack conductivity by taking into account the fluid cleanup period. Nitrogen was used in the flowback to simulate the gas production conditions. The test design used a rock core on top of the proppant bed and measured conductivity at standard conditions. Then, gel was injected through the proppant pack to create a filter cake and finally simulate a cleanup period flowing nitrogen through the proppant pack. This investigation concludes that the leakoff coefficient is a function of the square root of the pressure differential over the filter cake.

In 1987, Stimlab made two changes to the Cooke conductivity cell, first the steel pistons were replaced by Ohio sandstones, and second two temperature values were used (150 °F and 250 °F) (Much and Penny, 1987). The standard procedure was documented in API-61 (API, 1989) where proppant is loaded at a specific concentration (e.g. 2 lb/ft2) between two core slabs (Ohio Sandstone) in an API conductivity cell. The proppant pack conductivity is then measured few times at a stress level until it is stabilized, normally within 50 hours. This procedure is the standard for long-term testing of proppant packs. In 2007, it become ISO 13503-5 standard (Kaufman et al., 2007).

Parker and McDaniel (1987) conducted a series of experiments evaluating the effect of fluid loss filter cakes on the fracture conductivity. Their results showed that gel damaged decreased the fracture conductivity under the same closure stress over time.

Hawkins (1988) studied the reduction of fracture conductivity caused by fracturing fluids. The necessity of breaker and minimization of crosslinker and polymer concentration was concluded in this research.

Freeman, et al. (2009) studied the effect of high temperature, closure stress and fluid saturation on proppant crushing. Two crush resistance tests were performed using high strength bauxite at 15,000 and 20,000 psi at 400 ºF and 500 ºF. It was found that pressurized fluid saturation, increased temperature and extended stress loading increase the occurrence of proppant failure.

Marpaung (2007) design a new experimental apparatus for dynamic fracture conductivity test to investigate damage resulting from unbroken polymer gel in the proppant pack. This study simulates fracturing fluid cleanup characteristics and investigates damage resulting from unbroken polymer gel in the proppant pack. Marpaung conduct series of experiment using dynamic fracture conductivity procedure to identify the effect of production rate on fracture conductivity by simulating field condition for tight gas reservoirs (2007).

At present, there is significant information available on the behavior of high proppant concentration packs at temperatures and pressures equivalent to tight gas reservoirs. However, there is very little data on the behavior of low proppant concentration packs at different closure stress and different polymer concentrations, breaker additives and temperature. This research, therefore, will conduct a series of experiments using different concentrations of polymer (10 lb\1000 gal and 30 lb\1000 gal) to study fracture conductivity and gel clean-up in the proppant pack. The behavior of proppant placed inside the fracture, the effect of different proppant concentrations in the slurry and the effect of closure stresses on gel clean up in proppant pack will be identified. The effect of breaker, temperature and gas rate on fracture conductivity will also be examined.

1.3 Problem Description

Most of the previous experimental researches on fracture conductivity were carrying out using a static conductivity cell. In these experiments the proppant was placed inside the conductivity cell and then the fracture fluid was pumped through the cell. This procedure underestimates the ability of the fluid to carry the proppant and just evaluates the damage caused by the gel in the proppant pack. This project uses a dynamic conductivity apparatus to study gel damage. This new approach simulates the process of the fracturing fluid and proppant mixing and pumping and examines the combinations of parameters such as polymer and breaker concentrations, among others, affect the fracture conductivity.

The results of this new approach could lead to optimize the design of fracturing treatment in tight gas formation to obtain sustained fracture conductivity and effective cleanup of the fracture pack after stimulation.

1.4 Research Objective

This research has been conducted in a group effort in Texas A&M University. The overall objective of this project is to be able to predict with more accuracy the conductivity of a hydraulic fracture created in a tight gas well under certain conditions of temperature, proppant and polymer loading, gas flow rate, breaker concentration and closure stress.

The specific objectives of this study include:

1. Modify the actual experimental apparatus to carry dynamic fracture conductivity tests and the procedure that will be used to study the effects of long-term high temperature (up to 250°F) and high closure stress (up to 6000 psi) on proppant pack conductivity.

2. Conduct experiments to determine the effect of fracture fluid and its components and additives on fracture conductivity at different conditions of closure stress, temperature and proppant concentration. The factors involve in this study are:
    i. Polymer loading concentration.
    ii. Breaker concentration.
    iii. Gas flow rate.
3. Provide recommendations for hydraulic fracture treatment design to minimized gel damage in tight gas formations.

CHAPTER II

EXPERIMENTAL SET UP, PROCEDURES, AND CONDITIONS

2.1 Dynamic Fracture Conductivity Test

Since 1975 different investigators have been studying different methods and factors to increase the effectiveness in a hydraulic fracture treatment. Most of these studies have been carried out in conductivity cells in a way to simulate the fracture created during a hydraulic fracture treatment and evaluate the materials used and their respond to different conditions of pressure and temperature.

Most of these researches have been focused on two types of investigations, first, estimate the long-term effects of closure stress on proppant packs and it effect on proppant crushing and proppant pack conductivity, and, second, estimate the effect of fracturing fluids under specific conditions of pressure and temperature on fracture conductivity.

One of the first investigations was performed by Cook (1975) over three decades ago. Since then numerous studies have been conducted utilizing as a base the original conductivity cell design by Cook and adding several design improvements, including the utilization of core samples instead steel pistons, the use of temperature and pressure to simulate reservoir conditions, the use of producing fluids like gas and oil and finally the procedure to place dynamically the proppant inside the fracture.

The standardization of those tests was made by the American Petroleum Institute (API) under API RP-60 to test the strength of proppants in February 1985 and API RP-

61 for evaluate proppant pack conductivity on October 1989 (API, 1989). On May 2008 “ANSI/API RECOMMENDED PRACTICE 19D” and “ISO 13503-5” was elaborated as an update of API RP-61 to measure the long-term conductivity of proppants.

In this research the proppant was placed dynamically between two Ohio sandstone core samples and conductivity measurements were taken by injecting wet nitrogen through the conductivity cell measuring differential pressure across the cell. In order to further accurately represent field conditions, fracturing fluids containing proppants screened to a 30-50 mesh tolerance was pumped through the space between the core samples with different concentrations of breaker. The purpose of developing this procedure was to provide an appropriate scaling to field conditions and a better understand of gel damage, fluid cleanup and proppant behavior.

To accomplish the goals, this study was divided in four main parts: Design of experiments, experimental apparatus and setup, experimental procedure and experimental conditions.

2.2 Design of Experiments

Several parameters, whether from reservoir or fracture fluid, are involved in the design of the experiments to determine the final fracture conductivity on a laboratory simulated hydraulic fracture. Considering that to obtain the effect of the parameters and its combinations could take run a large number of experiments, in our case $2^6 = 64$, an experimental strategy based on fractional factorial design methodology was used to minimize the number of experimental runs while maximizing the information content of each run and identifying those factors that have large effects.

2.2.1 Generating the Design

The design displayed on the Table 1 should be interpreted as follows: each column contains +1's or -1's to indicate the setting of the respective factor (high or low, respectively) as it can be observed in Table 2.

Table 1—Experiment and factor indicator.

Schedule 1	A	B	C	D	E	F
Experiment	N2 Rate (SL/min)	Temperature (℉)	Polymer loading (lb/1000 gal)	Breaker concentration	Closure stress (psi)	Proppant conc. (ppa)
1	-1	-1	-1	-1	1	1
2	-1	-1	1	1	-1	-1
3	-1	1	-1	1	-1	1
4	-1	1	1	-1	1	-1
5	1	-1	-1	1	1	-1
6	1	-1	1	-1	-1	1
7	1	1	-1	-1	-1	-1
8	1	1	1	1	1	1

Table 2—Value of factor indicator.

	N2 Rate (SL/min)	**Temperature (℉)**	**Polymer loading (lb/1000 gal)**	**Breaker concentration**	**Closure stress (psi)**	**Proppant conc. (ppa)**
High	**3.0**	**250**	**30**	**Normal**	**6000**	**2.0**
Low	**0.5**	**150**	**10**	**No**	**2000**	**0.5**

Once the experiments were run and the results generated, the fracture conductivity value is store in the matrix “y”. The design table is store in the matrix “x” and the product of these matrixes, “x” and “y”, is used to find the effect of the parameters and its allies (Figure 2).

$$x = \begin{bmatrix} -1 & -1 & -1 & -1 & 1 & 1 \\ -1 & -1 & 1 & 1 & -1 & -1 \\ -1 & 1 & -1 & 1 & -1 & 1 \\ -1 & 1 & 1 & -1 & 1 & -1 \\ 1 & -1 & -1 & 1 & 1 & -1 \\ 1 & -1 & 1 & -1 & -1 & 1 \\ 1 & 1 & -1 & -1 & -1 & -1 \\ 1 & 1 & 1 & 1 & 1 & 1 \end{bmatrix} \qquad y = \begin{bmatrix} y1 \\ y2 \\ y3 \\ y4 \\ y5 \\ y6 \\ y7 \\ y8 \end{bmatrix} \qquad x \times y = \begin{bmatrix} \beta 1 \\ \beta 2 \\ \beta 3 \\ \beta 4 \\ \beta 5 \\ \beta 6 \\ \beta 7 \\ \beta 8 \end{bmatrix}$$

Matrix design Fracture conductivity values

Figure 2— Operations between the parameters.

All the aliasing relations are obtaining through operations between the parameters (Figure 3). The key to selecting appropriate fractional factorial designs is to identify design generators, which are ordinarily high-order interactions that divide the test runs for a complete factorial into fractions that have desirable properties.

A	D=ABC	I=ABCD	ACF*BCE=ABEF
B	E=BC	I=BCE	ACD*ABCD=BDF
C	F=AC	I=ACF	BCE*ABCD=ADE
			ACF*BCE=ABEF*ABCD=CDEF

	ACF	BCE	ADE	BDF	ABCD	ABEF	CDEF
A	CF	ABCD	DE	ABDF	BCD	BEF	ACDEF
B	CE	DF	ABDE	DF	ACD	AEF	BCDEF
C	AF	BE	ACDE	BCDF	ABD	ABCEF	DEF
D	ACDF	BCDE	AE	BF	ABCDF	ABDEF	CEF
E	ACEF	BC	AD	BDEF	ABCDE	ABF	CDF
F	AC	BCEF	ADEF	BD	ABCDF	ABE	CDE

Figure 3—Aliasing generation.

Applying the same methodology and generating a second schedule with the same parameters but with the inverse factor, the equations set necessary to obtain the values for A, B, C, D, E and F are complete (Figure 4).

$$
\begin{array}{lll}
A+CF+DE=\beta 1 & A-CF-DE=\beta' 1 & \qquad A=(\beta 1+\beta' 1)/2 \\
B+CE+DF=\beta 2 & B-CE-DF=\beta' 2 & \qquad B=(\beta 2+\beta' 2)/2 \\
C+AF+BE=\beta 3 & C-AF-BE=\beta' 3 & \Rightarrow \quad C=(\beta 3+\beta' 3)/2 \\
D+AE+BF=\beta 4 & D-AE-BF=\beta' 4 & \qquad D=(\beta 4+\beta' 4)/2 \\
E+BC+AD=\beta 5 & E-BC-AD=\beta' 5 & \qquad E=(\beta 5+\beta' 5)/2 \\
F+AC+BD=\beta 6 & F-AC-BD=\beta' 6 & \qquad F=(\beta 6+\beta' 6)/2
\end{array}
$$

Figure 4—Final equations.

2.3 Experimental Apparatus Setup

The experimental apparatus setup consists of three main components, base gel and fracture fluid mixing and pumping stage, gas flow production and fracture conductivity measurement.

The base gel and fracture fluid mixing and pumping consists of the following:

- 5 gallon bucket and paddle mixer (Caframo ZRZ50)
- Mixer drum (capacity 55 gal)
- Plastic drum (capacity 30 gal)
- Centrifugal pump (4 GPM, max pressure 390 psi)
- 2 jet pumps (Dayton 1hp, Franklin electric 1 hp)
- Stainless steel pipe (OD 1/2 in, working pressure 3000 psi)

- Grounded heating tapes (GlasCol, max temp 480°F)
- Thermocouple (Type J)
- Ph meter (SM102 Milwaukee, range: 0.00 - 14.00 pH)
- Temperature controller (GlasCol DigiTroll II)
- Waste drum (capacity 55 gal)

The simulated gas production and fracture conductivity measurement consists of the following:

- Modified API RP-61 fracture conductivity cell (API 1989)

The fracture conductivity cell used in this research is a modified API RP-61 conductivity test cell. The cell is made of 316 grade stainless steel and has been milled to accommodate the exact dimensions of the silicone surrounded core samples.

The fracture conductivity cell has three parts: the cell body, two pistons and two side inserts. The dimensions of the cell body are 10 in long, 3.25 in wide and 8 in tall. To avoid a leak of fluid around the cores, two O-rings are setting inside the cell (Figure 5). The cell has three ports used to measure the pressure inside the cell. The middle port is used to measure the cell pressure while the ports at each side are using to measure differential pressure. The ports are connected to pressure transducers through a 1/4 in OD line and a 140 micron filter is used to protect it. The dimension of the two pistons, top and bottom, is 3 in tall, both pistons have a Viton seals. These pistons are used to keep the cores in place and to transmit the pressure (closure stress) to the cores using hydraulic load frame. The side inserts have male-male NPT fittings fastened to them to connect the flow lines for the inlet and outlet of the cell.

Figure 5—Fracture conductivity cell and its parts.

- Heating jacket (GlasCol, Max temp 400°F)
- Temperature controller (GlasCol DigiTroll II)
- Load frame (GCTS 1646 FRM-1000-50S)

The compression frames “GCTS 1646 FRM-1000-50S” (Figure 6) is a closed-loop digitally servo controlled apparatus developed for accurately performing easy and quick load stress tests. Rapid, easy, and safe operation makes this compression frame system ideal for fracture conductivity tests. The compression frame is operated with an electro hydraulic power unit, servo valve, sensors, computer interface and testing software. The compression frame is operated with a Digital Servo Control software and hardware package conditioning increments testing reliability.

The compress frame “FRM-1000-50S” is a four column standing assemble with threaded columns for crosshead adjustment. Includes the following specifications: 2 inch stroke, the maximum static axial load capacity is 1000 kN and dynamic axial load capacity is 800 kN and a deformation sensor whit 50 mm range.

The electro hydraulic power unit (HPS-3-1) provides hydraulic pressure for all hydraulic testing systems. This device provides different flow rates ranging from 5 gpm up to 20 gpm. The pump is protected from over pressure using a relief valve and an electronic sensor that monitors fluid temperature. The HPS-3-1 is operated through remote operation via the system controller and software.

The controller is an embedded microprocessor based digital servo controller that is running the control program in a real time environment. It is the one that actually reads/writes to the boards, performs the requested test, saves the data file, etc. This is a complete and self-contained module featuring built in function generator, data acquisition, and digital I/O unit. Utilizing state-of-the-art Universal Signal Conditioning boards, this system can accept load cells, pressure transducers, LVDTs, or other analog input signals.

The uses can only interact with the controller through the software. However, the controller is independent form the software as the software does not need to be running in order for the controller to operate. It provides automatic dynamic control mode switching between and connected transducer or calculated parameter. This controller also conditions all transducers used for the test and provides real time linearization of any input using high-order polynomials. This digital controller has several adaptive compensation techniques to improve the control precision without user intervention.

Figure 6—Hydraulic load frame.

Included with this system is standard software graphical user interface with a universal test module that allows you to create a variety of wave forms. The standard system also includes calculated inputs from one or several analog channels that can be directly servo controlled or monitored in real time. Any system sensor can then be used to provide advanced servo control with "on-the-fly bump less" transfer switching between any connected transducer and calculated inputs.

Conducting the tests have been greatly simplified by the incorporation of direct user programming of test calculated parameters in the units of interest (stress, strain, etc.) based on the specimen dimensions. Up to 20 test parameters are automatically defined and corrected taking into account such things as piston force from closure stress pressure application, changes in fracture thickness during the test and variation of pressure inside the cell. These parameters are calculated in real time and are available for display, graph and/or control. In addition, the software allows you to define user defined parameters to obtain multiple sensor averages or corrections as a function of other inputs. Using calculated test parameters directly eliminates complex and lengthy pre-calculations to design test programs. This allows the user to concentrate on the material behavior rather than on the electronics and equipment operation. The software offers any desired unit can be used for display or report test parameters even allowing to combine different unit systems.

The multiple benefits when this compress frame is used are:

- Allow a high static and dynamic axial load capacity, 1000 kN and 800 kN respectively.
- Permit to conduct the tests and operation of compress frame using the control software.
- The frame can be programmed to run the test at a gradient ramp of pressure at a specific time or a constant pressure.
- All the data generated during the test is recorded for posterior analysis.

- Included a graphical user interface that allows you to create a variety of graphs using different inputs.
- The system also includes calculated inputs from one or several analog channels that can be directly servo controlled or monitored in real time.
- The system send preventative warning messages and instantaneous shutdown of the pump is provided if a critical limit has been detected. Time to reach critical limits, based on actual temperature and oil level trends, is automatically predicted by the software to prevent pump shutdown during tests on important or expensive specimens.

- Pressure Transducers

Low pressure sensors are used to measure the pressure difference across the cell using the outer two pressure ports of the cell and cell pressure using the middle port. Due the wide range of pressure is used several diaphragms with maximum pressure between 2.0 psi and 150 psi as is observed in Figure 7.

Figure 7—Pressure transducer port and diaphragms.

- Filters (140 microns)

Filters are used to prevent the flow of slurry through the pressure ports and in this way protect the pressure sensors and diaphragms. The filters use a 140 microns screen.

- Data acquisition system (GCTS SCON 1500 digital system) and desktop computer.

The SCON-1500 works as a controller, data acquisition, and digital I/O unit. The unit controls the electro hydraulic power unit, necessary to applied pressure to the cell. Additionally it receives the data from the pressure transducers and displays all the information in a graphical user interface on the desktop computer (Figure 8).

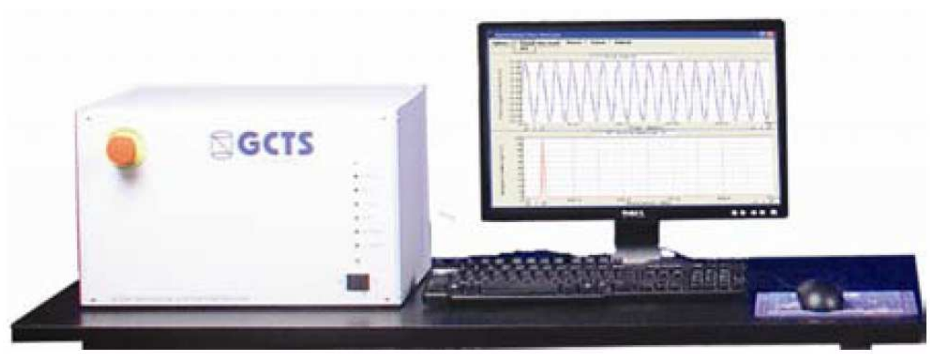

Figure 8—Data acquisition system and desktop computer.

2.4 Experimental Procedure

The procedure for dynamic fracturing test can be divided into several steps including core preparation, fracture conductivity cell preparation, base gel and fracturing fluid mixing and pumping, shut in and closure stress and fracture conductivity measurement.

2.4.1 Core Sample Preparation

The core sample used in this experiment is Ohio sandstone. This rock was chosen because of its low permeability, which closely represents a thigh reservoir. Tests running on Ohio sandstone samples indicate permeabilities between 0.012 and 0.015 mD. The dimensions of the cores used in this research are 7.00 in in length, 1.65 in wide, and 3 in height. The ends of the sandstone cores shall be rounded to fit into the cell. Additionally, to provide a perfect fit and seal inside the cell the core samples have to be surrounded with a silicone sealant. An example of core preparation is observed in Figure 9.

The procedure to prepare the core samples is as follows:

1. Place blue painters tape on top and bottom of the core sample and the edges must be cut.
2. Apply three times silicone primer (SS415501P) along the sides of the core samples. Wait 15 minutes between primer applications.
3. Clean the metal surface and bottom plastic piece of the mold with acetone.
4. Spray silicon mold release S00315 on the metal molds three times. Wait two minutes between each spray.
5. Assemble the mold. Tighten the four screws at the bottom and the three screws on the side.
6. Put the core sample in the mold and adjust to center position.
7. Weigh 45 g of silicone potting compound and 45 g of silicon curing agent from the RTV 627 022 kit. Mix both components and stir thoroughly using a disposable plastic container.

8. Pour the mixture in the gap between the core sample and the mold carefully until the mixture fills complete the gap.
9. Let mold set for 24 hours at room temperature or 4 hours in a laboratory oven at 200°F.
10. Remove the mold form the oven and wait until the mold temperature decrease.
11. Unscrew all the bolts from the mold and carefully remove the samples from the mold.
12. Cut extra silicon on the edges with a razor cutter.
13. Label the cores and remove blue painters tape from top and bottom of the core.
14. The core sample is ready to use.

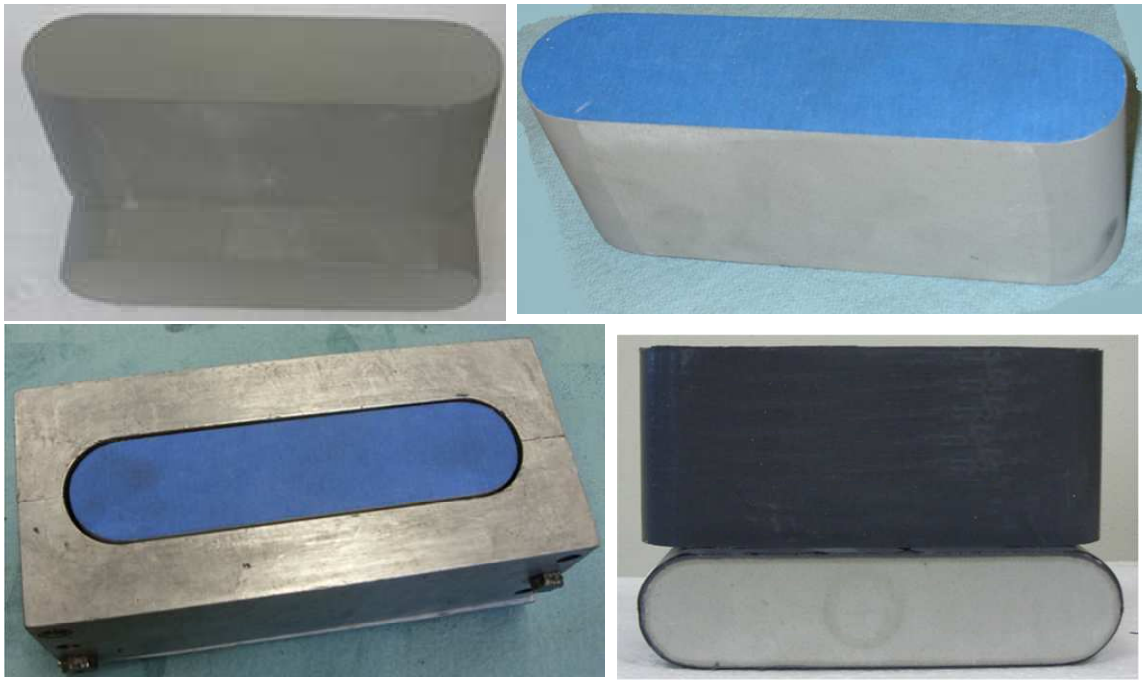

Figure 9—Core sample preparation.

2.4.2 Assembly of the Fracture Conductivity Cell

The procedure to assemble the fracture conductivity cell is:

1. Clean inside the cell and be assured that there are not sand or other particles inside. Check the o-rings inside the cell to determine if they need to be replaced.
2. Wrap each core, prepared using guideline from section 2.2.1, with five rows of teflon tape, one near the top and the other near the bottom, and apply vacuum grease around each row. The Teflon tape will help to provide a seal inside the cell.
3. Insert the bottom core sample into the bottom opening of the conductivity cell using the hydraulic jack. This core will serve as the lower fracture face in the cell. Insert the lower piston and the support and press with the hydraulic jack press until the hydraulic jack gauge reads pressure. In this way the core lines up with the bottom of pressure ports in the cell. Plug the lower leak off port with a cap.
4. Insert the upper core sample into the upper opening of the conductivity cell using the hydraulic jack. To maintain the required space, use two metal pieces of 0.25 in between the cores, one in the inlet and other at the outlet of the cell. With the hydraulic jack press the upper core until the gauge reads pressure.
5. Put the conductivity cell in the center of the loading frame and using the computer interface move the piston until touch the upper piston of the cell.
6. The gap between the cores has to be 0.25 in. If the gap is greater than that move the loading frame piston until reach 0.25 in.

7. Plug the upper leak off port with a cap, put the side flow inserts into the cell with the letters on the inserts matching the letters on the cell and connect the pressure transducers in the ports. The setup should now resemble Figure 10.
8. Wrap the heating jacket around the conductivity cell and plug it to the temperature controller.
9. Set the temperature controller of the heating jacket to a predetermined temperature. Turn on the controller to heat up the heater. Note: due to a large amount of heat loss through conduction between the heating jacket and cell the cell must be preheated at a higher temperature for several hours.

The setup is now ready for pumping.

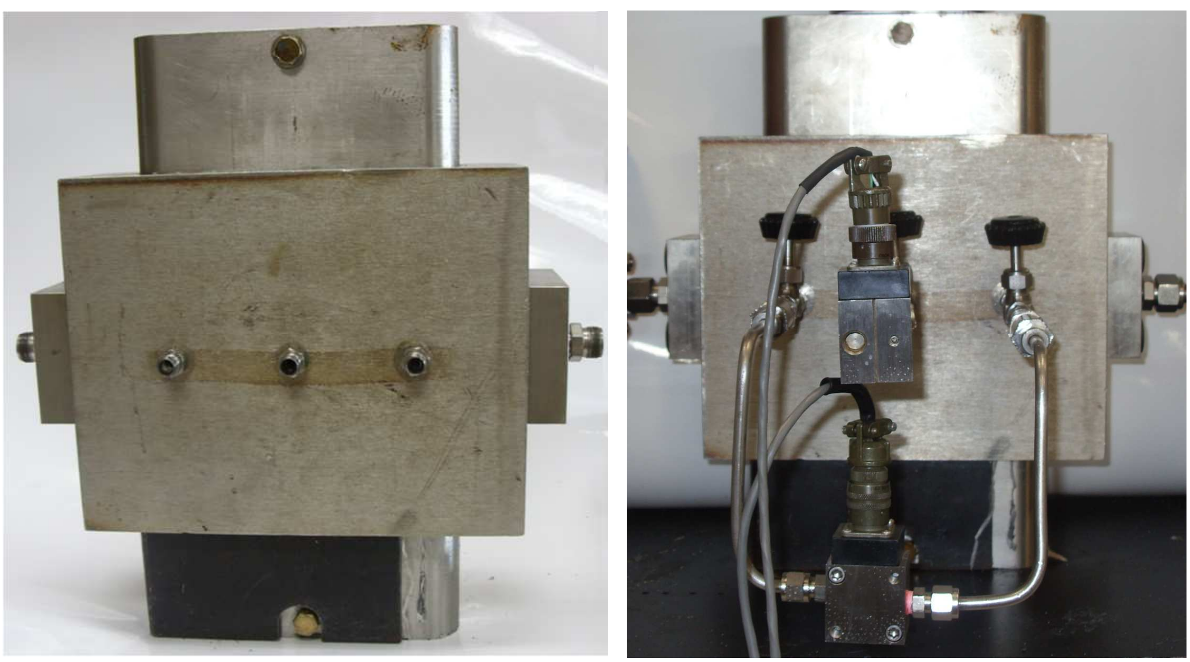

Figure 10—Fracture conductivity cell setup.

2.4.3 Gel and Fracture Fluid Preparation

The fluid used in this investigation is a delayed borate crosslinked using guar as a gelling agent. This fluid is used commercially in fields with similar characteristics to those used in this test (Closure stress from 2000 psi to 6000 psi and temperature from 150 °F to 250 °F). The chemical concentration of the components of the fluid is shown in Table 3. The mix procedure is detailed in the following steps:

Table 3—Fluid recipe based on temperature for fracturing fluid.

Chemical	150 F	200 F	250 F
Guar gelling agent , lb/M	10-30	10-30	10-30
Acid buffering agent to pH	6.5	6.5	6.5
Alkaline buffering agent to pH	10	10	10
Alkaline buffering agent to pH	None	10.5	11.5
High temperature gel stabilizer, gal/M	0	0	3
Oxidiser breaker, gal/M	10	10	5
Breaker activator, gal/M	1	0	0
Borate crosslinker, gal/M	0.9	1.05	1.2
Crosslink accelerator, gal/M*	0.3	0.3	0.3
*For polymer loading of 10 lb/M use 3 times crosslink accelerator.			

For base gel:

1. 19 gallons of tap water is added to the mixer drum.
2. A buffering agent is added to decrease the Ph to 6.5 to ensure hydration.
3. Guar gelling agent is added and mixed during 30 minutes.
4. Transfer the fluid from the mixer drum to the plastic drum.

For fracture fluid:

1. 4 gallons of tap water is added to 5 gallon bucket.
2. An acid buffering agent is added to decrease the pH to 6.5 to ensure hydration.
3. Guar gelling agent is added and mixed during 30 minutes with a paddle mixer.
4. An alkaline buffering agent is added to increase the pH of the aqueous base gels to 10.
5. If the reservoir temperature is greater than 175°F is necessary to add a pH control agent.
6. When the temperature is above of 225°F is necessary to add a high-temperature gel stabilizer.
7. The use of oxidizer breaker and breaker activator varies depending on the design of the experiment. If the experiment requires the use of breaker or breaker activator then add them at the necessary concentration.
8. Add borate crosslinker and crosslinker accelerator. They are used to increase the viscosity of the fluid.
9. Once the fracture fluid was hydrated and all the buffers, breakers, and cross linker were added and mixed, the proppant is added at the concentration describe in the experiment design. The proppant concentration varies between 0.5 ppg and 2 ppg.
10. Once the fracture fluid were hydrated and all the buffers, breakers, cross linker and proppant were added and mixed is transferred from the bucket to the mixed drum.
11. First is pumped the base gel through the cell, maintaining a rate close to 1 gpm.

12. Switch the proper valves to change from the base gel to fracture fluid. Maintain an optimum rate to avoid plug the pipe and to protect the centrifugal pump.
13. Close the valves at the inlet and outlet of the cell when proppant distribution is lower than the original at the beginning of the injection. Use the bypass to clean the line and pump water for 20 minutes to protect the pump.
14. During pumping, the pipe and the cell were heated using a heating tape and heating jacket at predetermined temperature, a J type thermocouple control the fluid temperature inside the pipe. The fluid is collected in a waste drum.
15. The schematic of the apparatus for conductivity measurements is shown Figure 11.

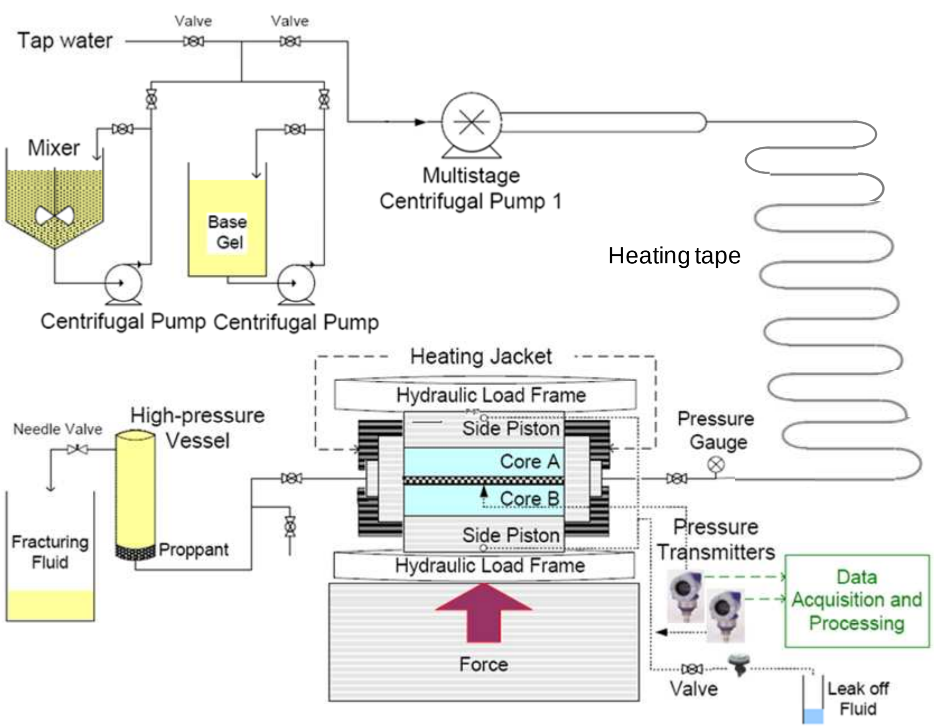

Figure 11—Schematic representation of fracture conductivity experiment.

2.4.4 Closure Stress Shut-in

Closure stress is the pressure at which the fracture closes after the fracturing pressure is relaxed, is determined by the overburden pressure (a function of depth and rock density), pore pressure, Poisson's Ratio, porosity, tectonic stresses, and anisotropy. Rocks with high closure stress are harder to frac (take more horsepower) than the same rocks with lower closure stress.

During this experiment the closure stress shut in procedure is as follows:

1. Open the windows interface GCTS C.A.T.S. Standard.
2. In the upper pane, click on File, Projects.
3. The Project/Sample/Specimen window will be open.
4. Click on RPSEA project or create a new project.
5. Click on RPSEA-TEST sample or create a new sample.
6. Click on New specimen and type the information required and then click OK.
7. The Universal Test Setup window will be open. Click on one of the programs or click on New to create a new program.
8. The information necessary is Duration (time of the test), Data Acquisition (record data at time interval), and finally Ramp, to chose the ramp type time and pressure. Click OK.
9. On the Universal Test-Control window click Run to start the closure stress simulation.

During the length of time of the test, the hydraulic frame will apply a force over the large surface area of the cell, simulating in this way the formation closure stress.

2.4.5 Fracture Conductivity Procedure

1. Measuring fracture conductivity is a long process that can take up to 48 hours. Below is the procedure for measuring fracture conductivity.
2. Follow the guideline for core preparation, rock permeability measurement, and fluid pumping. Before start the procedure for measuring fracture conductivity is necessary to calibrate the pressure transducer.
3. To calibrate the pressure transducers open the windows interface GCTS C.A.T.S. Standard.
4. In the upper pane, click on System, Inputs, Analog the Analog Inputs window will be open.
5. To calibrate the pressure inside the cell click on Al-4: Abs Pressure on the Analog the Analog Inputs window.
6. Click on Calibrate, the window Calibration Type Selection will be open.
7. Select 2 point, next select the max and min pressure of the diaphragm to use in the pressure port and then click Ok. The diaphragm to use to measure absolute pressure needs to read pressures between 0 and 100 psi.
8. Connect the pressure transducer to a nitrogen source with a reference gauge, set the First Calibration Point in zero psi and click Next when the reference gauge will be zero. Set the Second Calibration Point in 50 psi and click Next when the reference gauge will be 50 psi. Repeat the first and second calibration points and then click Ok.
9. To calibrate the differential pressure inside the cell click on Al-5:_Diff Pressure on the Analog Inputs window.

10. Click on Calibrate, the window Calibration Type Selection will be open.
11. Select 2 point, select the max and min pressure of the diaphragm to use and click Ok.
12. Connect the pressure transducer to a nitrogen source with a reference gauge, set the First Calibration Point in zero psi and click Next when the reference gauge will be zero. Set the Second Calibration Point in 40% of the maximum pressure of the diaphragm to calibrate and click Next when the reference gauge get the pressure. Repeat the first and second calibration points and then click Ok.
13. Connect the pressure transducers to the ports of the cell. Once the pressure transducers are calibrated and the closure stress is applied to the cell, the procedure continues to measure fracture conductivity.
14. Open the valves next to the pressure ports and at the inlet and outlet of the cell, let for 5 minutes to relax the pressure and record values for absolute pressure and differential pressure.
15. Open the nitrogen regulator and mass flow controller to flow gas into the conductivity cell.
16. Check all lines for leakage. Close the nitrogen regulator if leakage is found and repair the leak.
17. Adjust nitrogen regulator, back pressure regulator, and mass flow controller until the cell pressure reading reaches 50 psi and the gas flow rate reaches 2 slm.
18. Wait until flow rates and pressure readings stabilize and record the gas flow rate, cell pressure, and differential pressure.

19. Vary the gas flow rate from 2 to 10 slm to get five data sets at cell pressure of 50 psi. To increase gas flow rate, open the nitrogen regulator.
20. After reading 5 points, close the nitrogen regulator up to get a continue flow of nitrogen at a low predetermined rate for a predetermined time.
21. After flowing nitrogen at the predetermined rate for certain time (in this experiments 2 hours), repeat step 15 to 18 to get data points for the fracture conductivity calculation.
22. Once the test is finish, turn off the nitrogen flow and disconnect all lines to the conductivity cell.
23. Remove the rock sample from the cell with the hydraulic jack.
24. Calculate the fracture conductivity by using Forcheimer's equation.

$$\frac{(P_1^2 - P_2^2)Mh}{2ZRTL\mu\rho q} = \frac{1}{k_f w} + \frac{\beta\rho q}{w^2\mu h}$$

25. To calculate fracture conductivity (kfw) from the experimental data, the Forcheimer's equation Eq. 2.1 can be arranged as a straight line equation $y = mx + c$, using $\frac{\rho q}{\mu h}$ as the x-axis and $\frac{(P_1^2 - P_2^2)Mh}{2ZRTL\mu\rho q}$ as the y-axis. The y-intercept is the inverse of the fracture conductivity (kfw). Pressure drop $(P_1^2 - P_2^2)$ and cell pressure was measured along the fracture under five different gas flow rates. Fracture conductivity was measured at different times to study the fracture fluid clean up characteristic and gel damage.

The schematic of the apparatus for conductivity measure test is shown Figure 12.

The variables used in Forcheimer's equation for conductivity calculations are:

(h)	Width of fracture face	1.75	in
(L)	Length over pressure drop	5.25	in
(z)	Compressibility factor	1.00	
(R)	Universal constant	8.3144	J/molK
(T)	Temperature	293.15	K
(M)	RMM of nitrogen	0.028	kg/kg mole
(μ)	Viscosity of nitrogen	1.759E-05	Pa s
(ρ)	Density of nitrogen	1.16085	kg/m^3

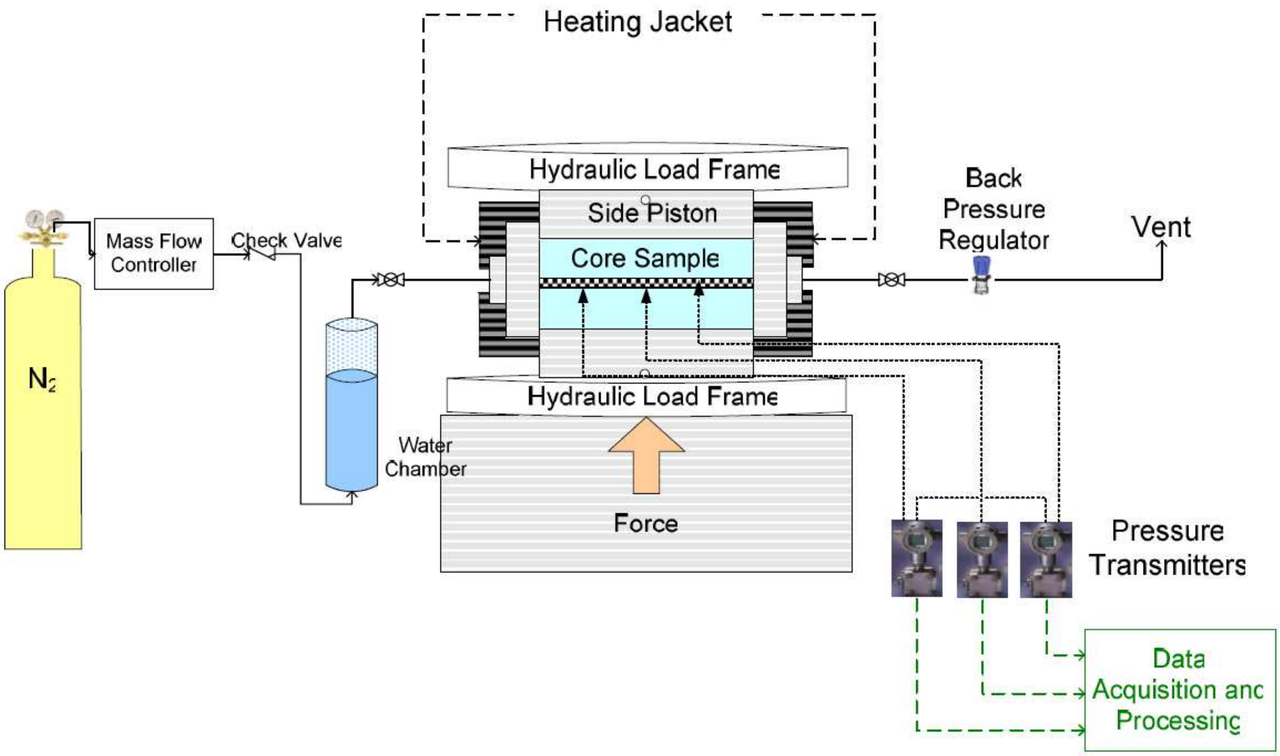

Figure 12—Schematic representation of conductivity measure test.

2.5 Experimental Conditions

In order to simulate thigh gas field conditions as accurately as possible and obtain valuable test results that could help the design of future hydraulic treatments, different test parameters were taken into account. These parameters and test conditions will be explained below.

2.5.1 Rock Sample

The rock used for the experiments was Ohio sandstone. This rock is quarried sandstone of low permeability with minimal clay reaction. The permeability of the Ohio sandstone core samples tested was between 0.012 and 0.015 mD.

2.5.2 Fracturing Fluid Composition

The fracturing fluids were mixed following the recipe with the desired polymer and other additives concentrations. The fluid composition was selected and provided by a service company for this experiment. This fracturing fluid was selected due to its similarity to the actual fracturing job operations in tight gas sands. All experiments were conducted at room temperature during the fluid preparation and injected into the conductivity cell at the desired temperature. The composition of the fracturing fluids used for the series of experiment is shown in Table 3.

The components for the selected fracturing fluid are as follows:

- Guar: Is a polymer used to formulate linear gels. This polymer is a dry powder that hydrates or swells when mixed with an aqueous solution and form a viscous gel.
- pH buffer: The buffer consistently maintains optimal fluid pH required for hydration and crosslink.

- Gel stabilizer: Increases the temperature stability of gelled fracturing fluids, resulting in a long-lasting, high-viscosity fluid at temperature.
- Breaker: Is a strong oxidizer who decreases the viscosity of fracture fluids.
- Crosslinker: Increase the fluid viscosity using borate ions to crosslink the hydrated polymers.
- Crosslink accelerator: Increase the crosslink velocity.

2.5.3 Proppant Size and Concentration

Proppant used in this experiment is lightweight ceramic proppant with a mesh size of 30/50. Since we will not study the effect of proppant size, 30-50 mesh proppant is appropriate to achieve the objective of this research. The concentration of proppant vary from 0.5 to 2 ppg, this range was decided because most of the “slickwater” or “waterfrack” treatments typically uses this low proppant concentrations.

2.5.4 Temperature

To replicate tight gas reservoir conditions, a range of temperature between 150°F and 250°F have been selected. The reservoir temperature has a large effect on fracture fluid properties and on proppant properties which leads to effects on fracture conductivity.

2.5.5 Nitrogen Gas Flow Rate

To simulate gas production from the fracture into the wellbore, wet nitrogen was used in these experiments. A flow rate for the laboratory setup was calculated to simulate a field production rate.

Table 4 is a comparison between field and laboratory conditions

Table 4—Comparison between field and laboratory conditions.

	Laboratory	Field
Fracture height (in)	1.6	100
Fracture width (w)	0.04	0.25
Temperature (°F)	150-250	250
Pressure (psi)	50	1000

Using the rate of gas at standard conditions, the rate at field conditions can be obtained.

Next are the steps and equations necessary to obtain the rate from laboratory to field.

1. $q_{sc} = q \times 0.0353 \left[\frac{ft^3}{min}\right]$
2. $B_g = \frac{ZTP_{sc}}{Z_{sc}T_{sc}P}\left[\frac{ft^3}{SCF}\right]$
3. $q = B_g q_{sc} \left[\frac{ft^3}{min}\right]$
4. $v_{lab} = \frac{q}{wh} \left[\frac{ft}{min}\right]$
5. $q = v_{frac}wh \left[\frac{ft^3}{min}\right]$

6. $$B_g = \frac{ZTP_{sc}}{Z_{sc}T_{sc}P}\left[\frac{ft^3}{SCF}\right]$$

7. $$q_{sc} = \frac{q}{B_g}\left[\frac{SCF}{day}\right]$$

Table 5—Scale flow rates for different reservoir flow rates at different temperatures.

q (slm)	q (scf/min)	Bg @ 150	q (cf/min)	v lab	Bg	q (cf/min)	q (SCF/day)
0.5	0.02	0.34	0.01	13.70	0.02	28.53	2.05E+06
3	0.11	0.34	0.04	82.18	0.02	171.20	1.23E+07
q (slm)	q (scf/min)	Bg @ 300	q (cf/min)	v lab	Bg	q (cf/min)	q (SCF/day)
0.5	0.02	0.43	0.01	17.06	0.02	35.55	2.55E+06
3	0.11	0.43	0.05	102.38	0.02	213.30	1.53E+07

Table 5 shows the results of the scaled flow rates for different reservoir flow rates at different temperatures.

2.5.6 Closure Stress Loading – Shut-in Time

The stress conditions implemented during the experiment to simulate the formation closure stress were 3000 psi and 6000 psi. These values were established as a low and a maximum value from conditions in tight gas reservoirs. The shut in time was 10 hours, this time was selected due to the fact that polymer is designed to break in approximately 5 hours.

CHAPTER III

EXPERIMENTAL RESULTS AND DISCUSSION

A series of fracture conductivity experiments were run in which different parameters were tested. These experiments were run using the procedure detailed in Chapter II. The parameters tested were temperature, closure stress, nitrogen flow rate, polymer loading, breaker concentration and proppant concentration. In order to minimize the number of experimental runs, maximize the information of every experiment and identify those factors with large effects on fracture conductivity, a statistical analysis knows as fractional factorial design methodology was implemented.

With the objective of finding the influences of these parameters, the design includes sixteen different fracture conductivity experiments under different conditions. Additionally, a detailed analysis is conducted over these three parameters, polymer loading, breaker concentration and nitrogen rate. The other parameters, closure stress, temperature and proppant concentration, are analyzed and explained in the thesis developed by Pieve 2011.

The conductivity value of several experiments, experimental data and photographs are presented in Appendix A.

3.1 Experimental Design

The results of this statistical analysis will help to determine the influence of the parameters on fracture conductivity. In order to minimize the number of experimental runs it is necessary design a series of experiments using two values for every parameter, one low factor and one high factor. The factors are listed in Table 6.

Table 6—Low and high factor indicator.

	N2 Rate (SL/min)	Temperature (℉)	Polymer loading (lb/1000 gal)	Breaker concentration	Closure stress (psi)	Proppant conc. (ppa)
High	3.0	250	30	Normal	6000	2.0
Low	0.5	150	10	No	2000	0.5

The design displayed in the Table 7 below show the conditions used in each experiment and the fracture conductivity value measured.

Table 7—Experiment schedule.

Exp.	N2 Rate (SL/min)	Temperature (℉)	Polymer loading (lb/1000 gal)	Breaker concentration	Closure stress (psi)	Proppant conc. (ppa)	Fracture conductivity (md-ft)
1	0.5	150	10	No	6000	2	531.95
2	0.5	150	30	Normal	2000	0.5	1226.69
3	0.5	250	10	Normal	2000	2	2011.77
4	0.5	250	30	No	6000	0.5	15.20
5	3	150	10	Normal	6000	0.5	960.00
6	3	150	30	No	2000	2	1060.87
7	3	250	10	No	2000	0.5	1098.58
8	3	250	30	Normal	6000	2	155.87
9	3	250	30	Normal	2000	0.5	688.75
10	3	250	10	No	6000	2	118.23
11	3	150	30	No	6000	0.5	15.30
12	3	150	10	Normal	2000	2	1477.00
13	0.5	250	30	No	2000	2	959.10
14	0.5	250	10	Normal	6000	0.5	476.03
15	0.5	150	30	Normal	6000	2	1232.19
16	0.5	150	10	No	2000	0.5	2485.40

3.2 Polymer Loading Effect

The fracturing fluid and reservoir characteristics used in this investigation are similar to the fluid used in the field in tight gas reservoirs. The fluid used in fracture treatments in this type of reservoirs is denominated by slick water. This fluid uses a low concentration of polymer. This investigation use two different polymer loadings, 10 lb/1000gal as a low value and 30lb/1000gal as high value.

The experiments were run modifying several parameters in order to observe the effect of every parameter in fracture conductivity. Figure 13 illustrates how, comparing the experiments ran with two different polymer loadings (10 lb/1000gal and 30 lb/1000gal) and under similar conditions of closure stress and temperature, polymer concentration has a direct effect on fracture conductivity.

The first set of experiments (1, 4, 8, 10, 11 and 14) showed a large difference in conductivity when polymer concentration is changed. These tests were run at high closure stress and temperature conditions. It was evidenced that experiment at a polymer loading of 30 lb/1000gal and a combination of high closure stress (6000 psi) and high temperature (250°F) has a polymeric cake inside the fracture. More residual gel is deposit inside the fracture at increased the polymer loading, creating this polymeric damage, reducing significantly fracture conductivity.

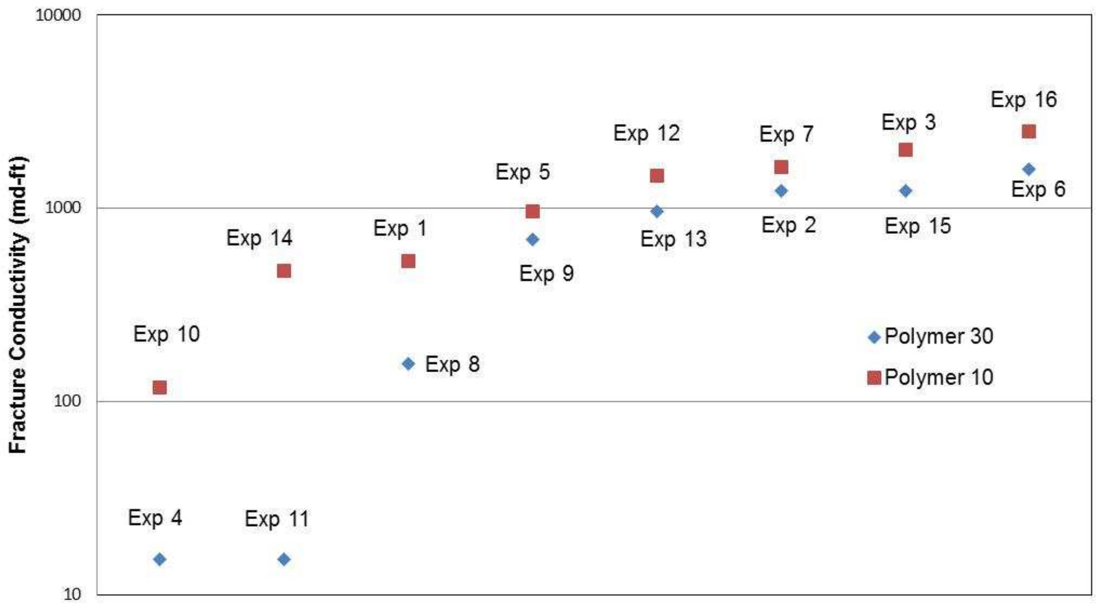

Figure 13—Comparison between experiments at 30 lb/1000gal and 10 lb/1000gal of polymer loading.

The gel damage may be characterized as the blocking of pore throats by unbroken viscous gel having limited mobility or, by insoluble polymer fragments. The proppant and residual gel are compacted by effect of high closure stress and high temperature, forming the cake outlined (Figure 14). The conductivity value for this experiment is extremely low (Figure 15), in reality, this conditions unsuccessful fracture job with extremely under performed gas rates.

Figure 14—Cake formed by proppant and residue gel.

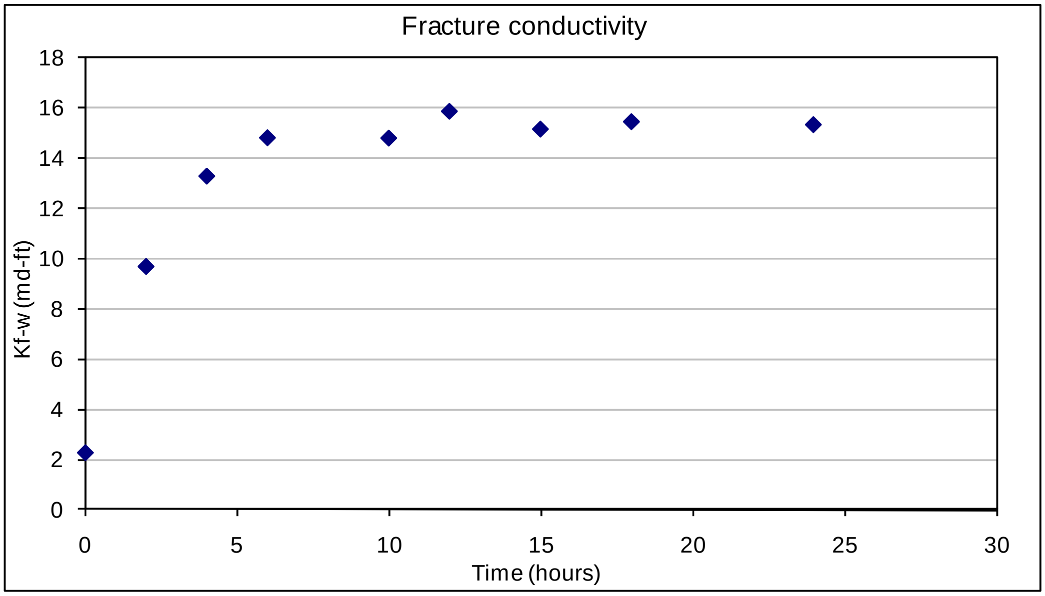

Figure 15—Fracture conductivity measurement.

When the fracture fluid with a polymer loading of 10 lb/1000gal was under high closure stress and high temperature (6000 psi and 250°F) the cake was not formed or formed in too small amounts. This can be explained because when a lower polymer loading was used, a small amount of residue gel was settled inside the fracture. Figure 16 shows a clean proppant pack and not extended cake observed.

The results confirm the positive effect on final fracture conductivity when a low polymer loading is used in a fracturing fluid. The main properties of the fracturing fluid observed in these experiments are the efficiency of the fluid to break and the effectiveness of the fluid to transport proppant. The experiments show that the use of less polymer concentration in the fluid does not affect the fluid property of proppant transportation and the amount of proppant inside the fracture when the fluid with 10 lb/1000gal was used is similar at the amount placed by the higher polymer loading fluid (30 lb/1000gal) (Figure 17).

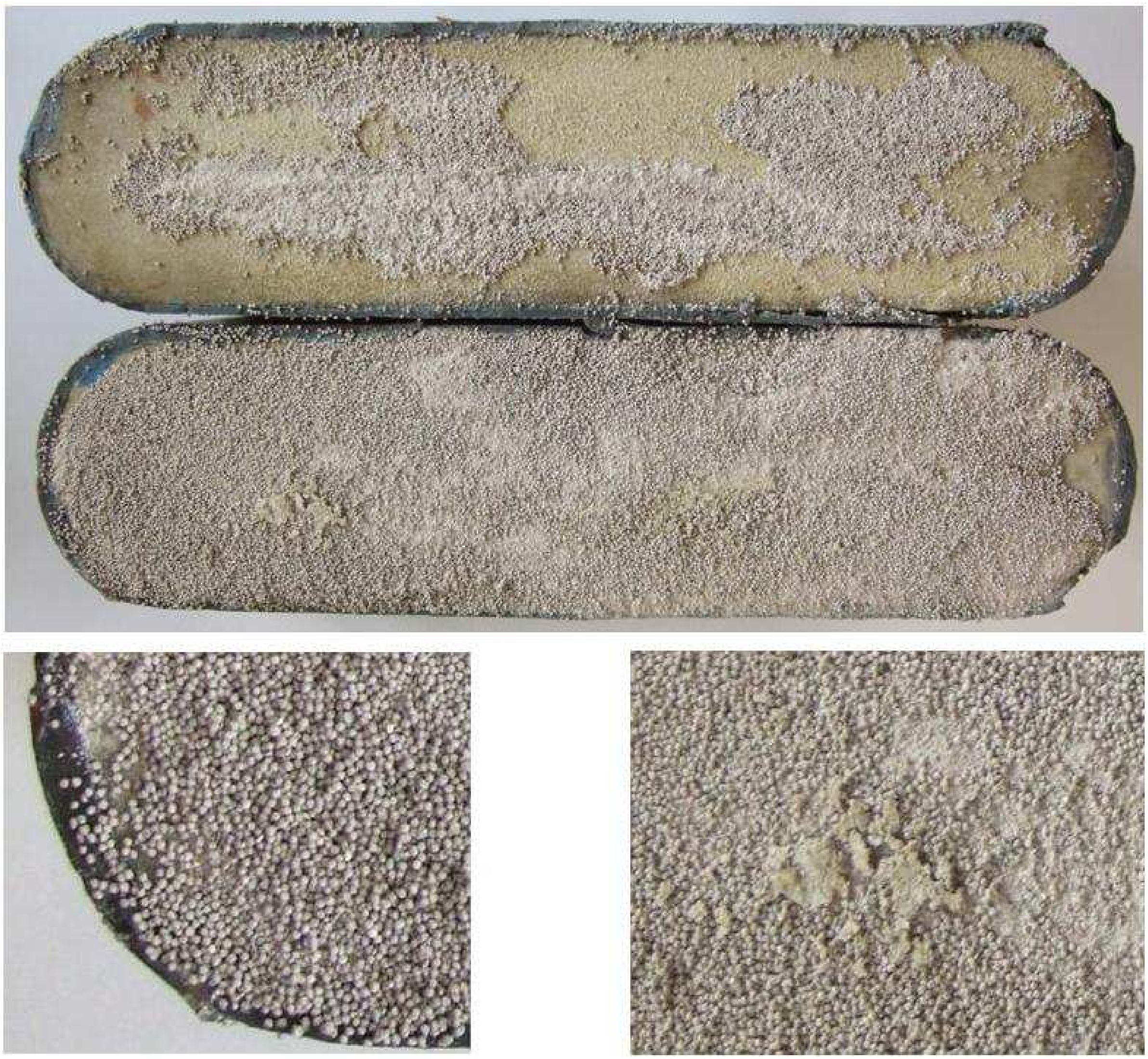

Figure 16—Proppant pack without polymer cake.

Instead, the amount of residue gel when the polymer loading increase in the fracturing fluid has a direct damage effect to the conductivity inside the fracture, as observed in Figure 14 and Figure 16.

30 lb/1000gal and 2 ppg

10 lb/1000gal and 2 ppg

Figure 17—Proppant pack comparison using fluids with two different polymer loading.

3.3 Breaker Concentration Effect

The breaker is added to the fracturing fluid to reduce the viscosity of the polymer-based carrier fluid, reducing the molecular weight of the polymer by cutting the long polymer chains, in order to remove it from the fracture after the stimulation treatment is completed. When the residual gel can not be removed, it causes damage to the proppant pack conductivity. Several experiments were carried out using fracturing fluids with normal concentration of breaker or no breaker at all to examine the effect of breaker on resulting conductivity.

The comparison between experiments designed with different breaker concentration is shown in Figure 18. At high conditions of closure stress and temperature, the final value of fracture conductivity is higher when breaker is added to the fracturing fluid than when is not used. When experiments with and without breaker are ran at lower values of closure stress (2000 psi) and similar conditions of polymer loading and proppant concentration, the final fracture conductivity has similar value.

Previous researches and analysis show that the presence of breaker has a positive effect on final fracture conductivity. It means when breaker is added to the fracturing fluid, the final fracture conductivity is higher than when no breaker is added to the fluid. The results from the experiments in this research show that at simulated higher reservoir conditions the effect of breaker on fracture conductivity is highly positive and when the closure stress is low the effect is not so evident.

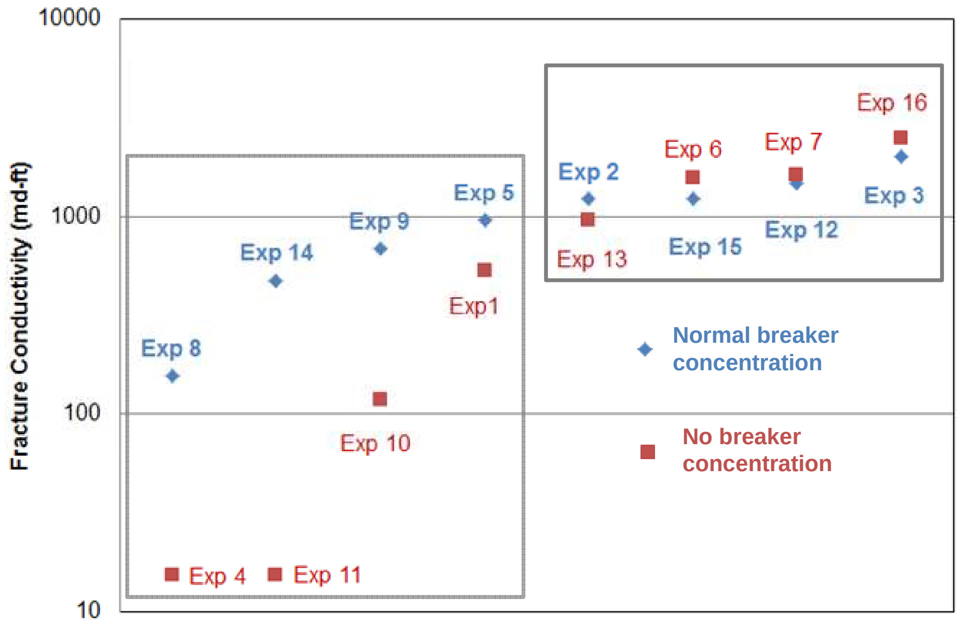

Figure 18— Comparison experiments with and without breaker.

3.4 Gas Flow Rate Effect

The general trend is higher gas flow rate increase the gel cleanup and fracture conductivity. Figure 19 represents fracture conductivity behavior for different experimental at similar reservoir and fluid conditions at different gas flow rates. The experimental data showed that the influence on gel cleanup efficiency is similar at different gas flow rates and high energy from gas flux is necessary to clean up the fracture. It was observed that flow rate does not have a significant effect on fracture clean up, which is opposite to what Marpaung (2007) conclude from his study.

The main reason of disagreement is probably due to the design of the experiments. The principal objective of the design of the experiments was to identify the effect of several parameters in fracture conductivity, and probably the effect of gas flow rate was limited on the final design of the experiments. The next step of experiments will aim to find the role of gas rate and the interaction between gas rate and low polymer loadings. Once these experiments are successfully completed, the information from this research could be more study in detailed and accuracy conclusions will be formulated.

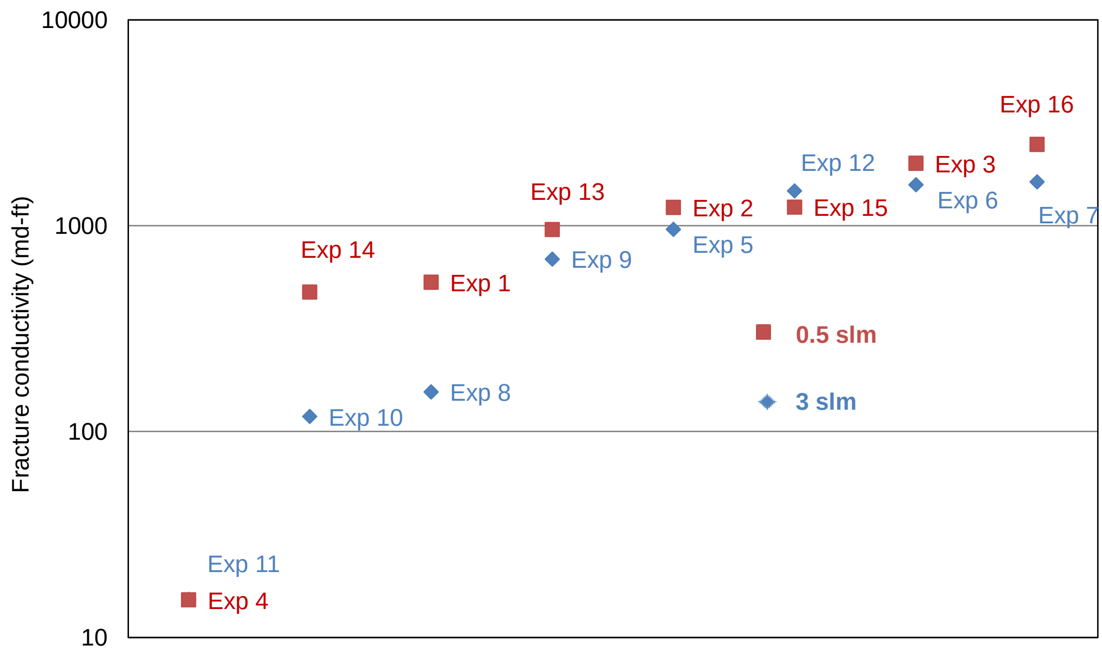

Figure 19— Comparison experiments at different gas flow rates.

CHAPTER IV

CONCLUSIONS AND RECOMMENDATIONS

4.1 Conclusions

Fracture conductivity tests were conducted under different conditions of temperature, proppant and polymer loading, gas rate, breaker concentration and closure stress. The following conclusions are made based on the statistical analysis and the results from experiments:

1. A dynamic conductivity testing apparatus was modify from the experimental apparatus used by Marpaung and Pongthunya (Marpaung, 2007; Marpaung et al., 2008; Pongthunya, 2008) to study the effects of high temperature (up to 250°F) and high closure stress (up to 6000 psi) on proppant pack conductivity and low polymer fluid. The new methodology permits the use of low polymer loading fluids and low proppant loading. Additionally new equipment was added allowing an accuracy application of closure stress during a specific time and better accuracy of pressure when fracture conductivity is measure.
2. The number of experiments and conditions of the experiments were design using an experimental strategy based on fractional factorial design methodology. The statistical analysis completed in this research is the first step that will lead to determine with more accuracy the effect of fracture fluid and its additives and the reservoir conditions on fracture conductivity.

3. An analysis and conclusions about the effect of pressure, temperature and proppant concentration on fracture conductivity can be obtained in the document named "Laboratory study to identify the impact of fracture design parameters over the final fracture conductivity using the dynamic fracture conductivity test procedure". In this chapter is presented the analysis of polymer loading concentration, breaker concentration and gas flow rate using the information obtained from the experimental tests.
4. Polymer concentration has a clear, but small impact on fracture conductivity. Higher polymer concentration will decrease cleanup efficiency. When polymer loading is increased in fracture fluid, the gel residue concentration in the fracture after closure increased too. The gel residue blocks the pore throats by unbroken viscous gel and by insoluble polymer fragments. At high closure stress and temperature, higher polymer concentration results in more obvious damage on proppant pack.
5. The use of breaker in fracture fluid increases cleanup efficiency, although, does not have a great impact on fracture conductivity when the simulated reservoir conditions are not extreme. The data from the experiments shows that when breaker was added to fracture fluid the clean up was better.
6. The analysis of nitrogen flow rate on cleanup efficiency and final value of fracture conductivity does not provide clear conclusion to support the previously published results. The previous conclusion was higher gas flux increases gel cleanup efficiency, although, in this research apparently the drag force at different flow rates was similar and the clean up was comparable.

7. As was outlined on 3.6, more experiments specifically design to describe the effect of gas rate, will be needed support this observations, as well the necessity of increase the accuracy on the gas rate control adding new equipment and reviewing the procedure in order to get more reliability.

4.2 Recommendations

The performing of dynamic conductivity testing experiments in a laboratory facility was successful, and the information collected in this tests can gives more representative field conditions than previous experiment. The experiments conducted produced many conclusions; however, additional testing under different conditions would add further valuable conclusions.

However, there is also some equipment that could be added to make the procedure of the experiment more consistent. A pump with capacity to pump slurry at high pressure and high volume is needed. An electronic feedback controller to regulate the gas flow rate also will reduce the potential for inconsistencies. The combination of these devices, along with a proper set up would automate a large portion of the experiment and will lead to a better understand of the parameters effect.

In order to study the influence of different variables on fracture conductivity in this investigation, an experimental design was used, but for further experiments some parameters would be considered constants in order to compare the results when just one parameter is varied.

As an additional part, the comparison of experimental fracture conductivity with the information of treatments from the field will help to set a more accurately experiment design and will reflect a better understanding of fracturing fluid clean up characteristic.

A phase behavior analysis could be developed to investigate the effect of fracturing fluid and residual gel at reservoir conditions.

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APPENDIX A

A.1 Experiment Schedule

Table 8–Experiment schedule and results.

Exp.	N2 Rate (SL/min)	Temperature (°F)	Polymer loading (lb/1000 gal)	Breaker concentration	Closure stress (psi)	Proppant conc. (ppa)	Fracture conductivity (md-ft)
1	0.5	150	10	No	6000	2	531.95
2	0.5	150	30	Normal	2000	0.5	1226.69
3	0.5	250	10	Normal	2000	2	2011.77
4	0.5	250	30	No	6000	0.5	15.20
5	3	150	10	Normal	6000	0.5	960.00
6	3	150	30	No	2000	2	1060.87
7	3	250	10	No	2000	0.5	1098.58
8	3	250	30	Normal	6000	2	155.87
9	3	250	30	Normal	2000	0.5	688.75
10	3	250	10	No	6000	2	118.23
11	3	150	30	No	6000	0.5	15.30
12	3	150	10	Normal	2000	2	1477.00
13	0.5	250	30	No	2000	2	959.10
14	0.5	250	10	Normal	6000	0.5	476.03
15	0.5	150	30	Normal	6000	2	1232.19
16	0.5	150	10	No	2000	0.5	2485.40

A.1.1 Experiment 1

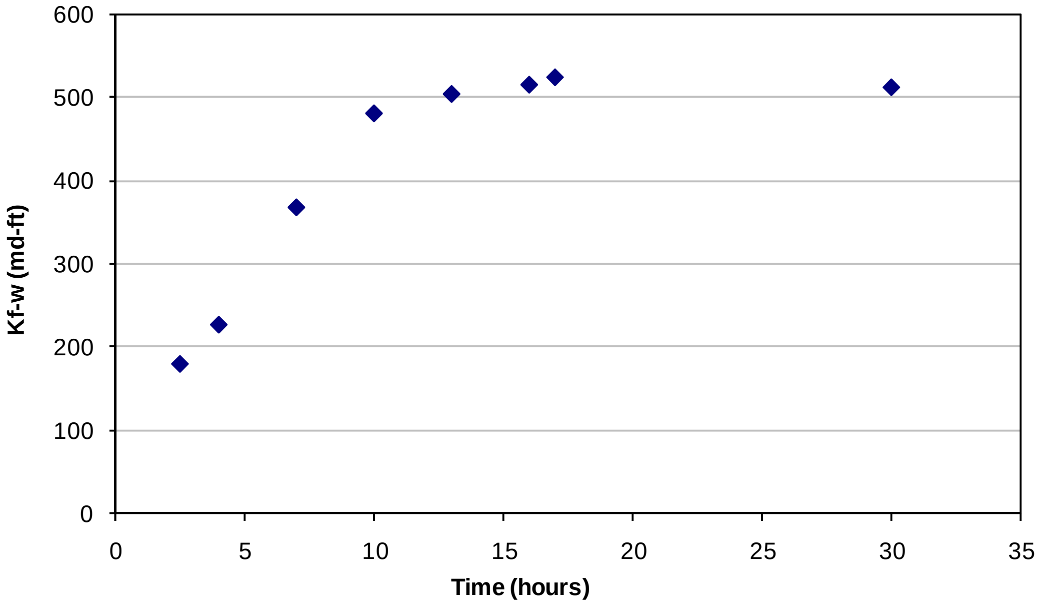

Figure 20–Fracture conductivity vs time. Experiment 1.

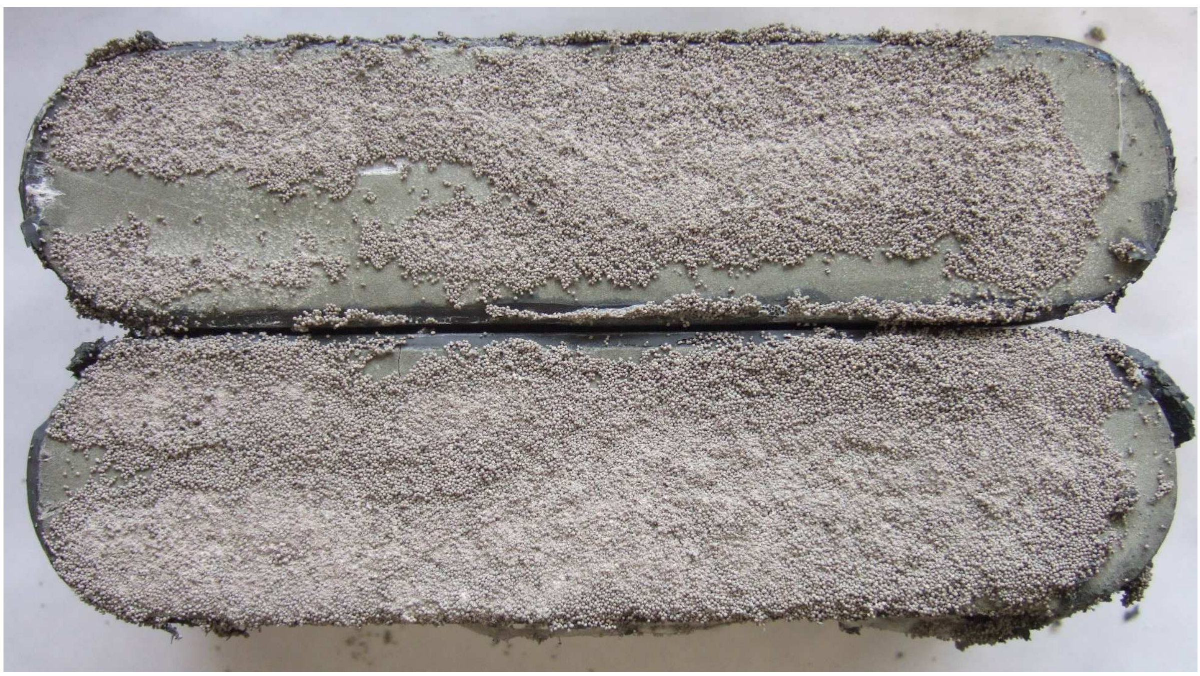

Figure 21–Proppant placed. Experiment 1.

A.1.2 Experiment 12

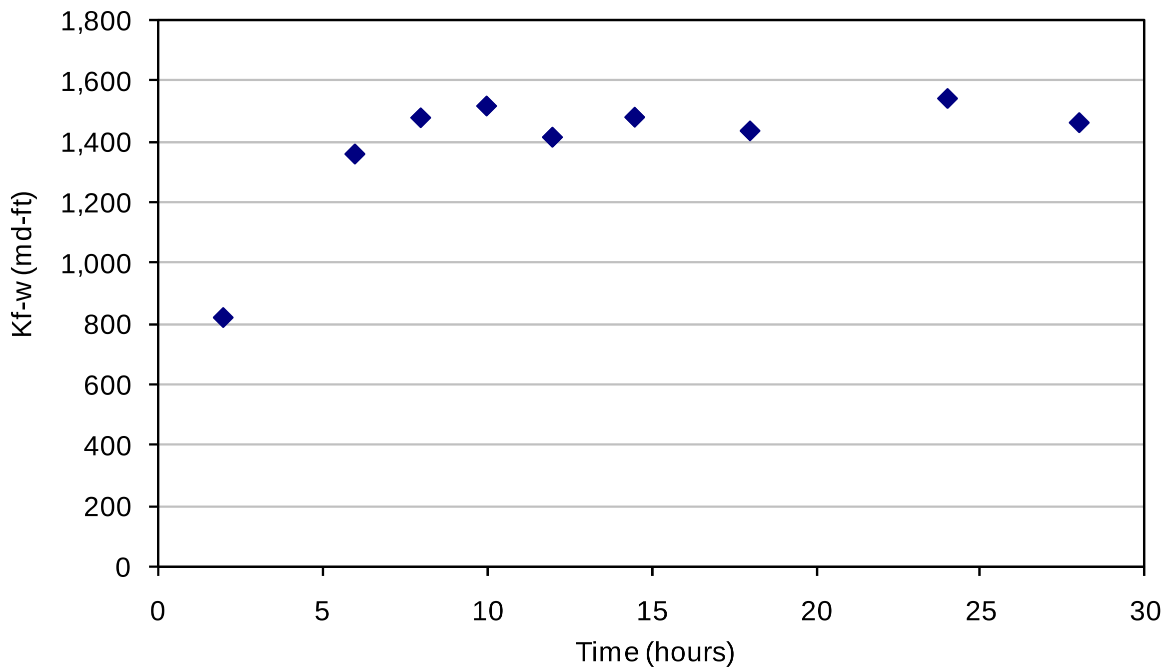

Figure 22–Fracture conductivity vs time. Experiment 12.

Figure 23–Proppant placed. Experiment 12.

A.1.3 Experiment 9

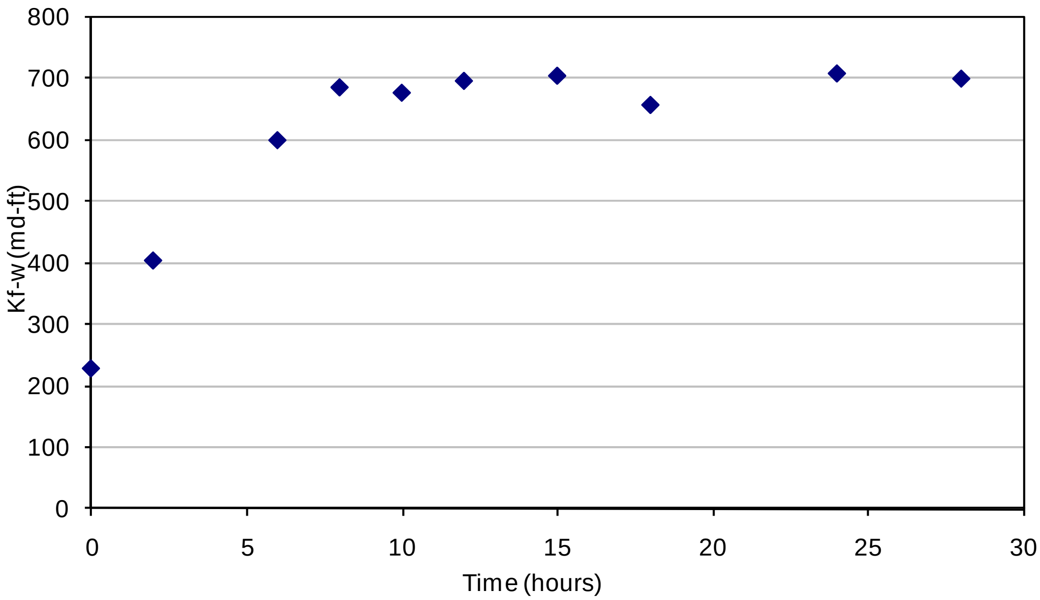

Figure 24–Fracture conductivity vs time. Experiment 9.

Figure 25–Proppant placed. Experiment 9.

A.1.4 Experiment 3

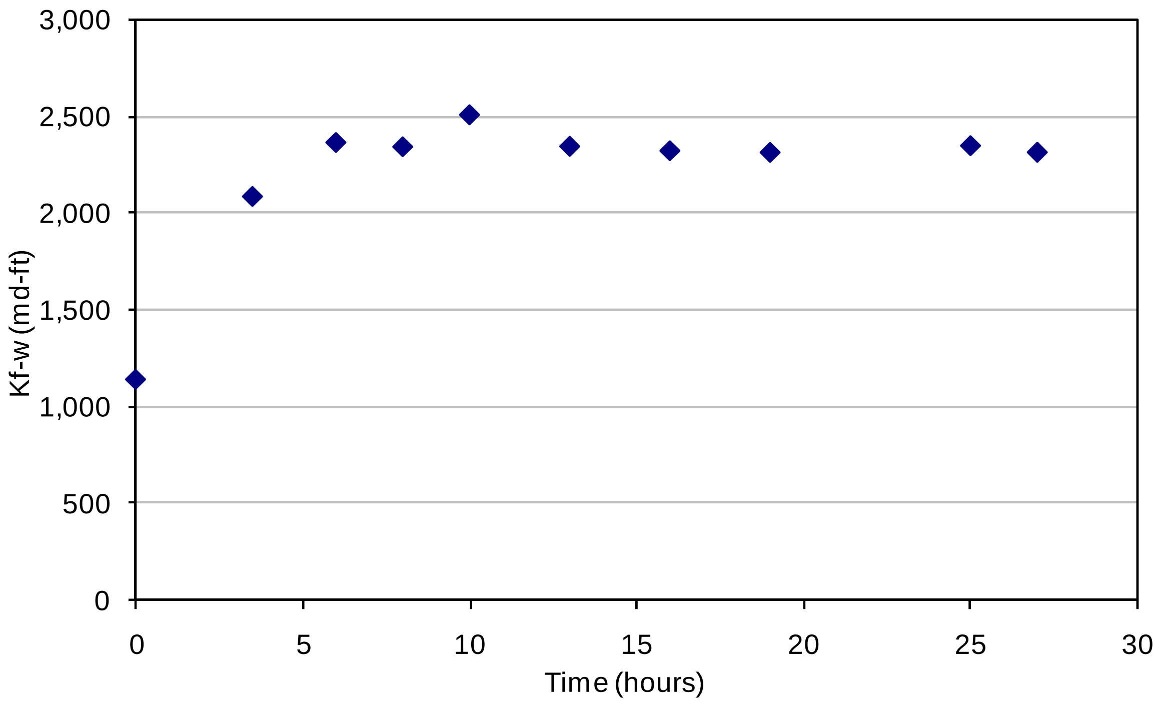

Figure 26–Fracture conductivity vs time. Experiment 3.

Figure 27–Proppant placed. Experiment 3.

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